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# Designing Tax and Subsidy Incentives Towards a Green and Reliable Electricity Market

Amin Masoumzadeh, Tansu Alpcan, *Senior Member, IEEE,* and Ehsan Nekouei, *Member, IEEE*

***Abstract*—Incentive schemes and policies play an important role in reducing carbon emissions from electricity generation. This paper investigates tax and subsidy incentives towards a reliable and low emission electricity market, using Australia's National Electricity Market (NEM) as a case study. A game-theoretical Cournot-based electricity market expansion model is developed, which calculates the capacity investment and retirement of any strategic/regulated generation, storage, and transmission player for multi investment periods, taking into account Emission Intensity Reduction and Fast Response Dispatchable Capacity constraints. Based on the dual variables of the emission reduction and the fast response generation constraints at the Nash Equilibrium solution of the game, the incentive policies (tax/subsidy) on emission and fast response capacity are designed, respectively. The simulation results for Australia's NEM during 2017-2052, indicates how large investment on solar thermal technology, battery storage and transmission lines supports high level of Variable Renewable Energy, wind and solar, penetration in a green and reliable electricity market. Improvement of new technologies and their cost reduction trajectory show that NEM does not need any emission incentive policy for up to 45% emission intensity reduction by 2052. However, higher emission reduction targets require imposing taxes on pollutant generators and subsidizing clean generators.**

***Index Terms*—Electricity market expansion model, Market power, Emission and fast response capacity incentive policies.**

## I. Introduction

### A. The Impotance of Incentive Policies in Electricity Sector

GREENHOUSE gas reduction from power generation has been firmly on the political agenda recently, following the international commitments under the Kyoto (1997) and Paris (2015) Agreements [1]. The policies imposing an emission target level in the electricity sector affects many existing fossil-fueled power plants as well as the future generation mix. For example, the U.S. Clean Power Plan incentivizes non-emitting electricity generation through the creation of a carbon price (Cap and Trade carbon policy) [2], and the US Renewable Portfolio Standards (RPS) require that load serving entities meet a minimum portion of their load with renewable electricity [3]. Although the decline in technology cost enables renewables to compete with fossil-fueled plants in electricity generation, the incentive policies can be used to accelerate the ongoing transition toward a green network.

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The emission reduction policies may lead to massive investment in renewable generation. High penetration of Variable Renewable Energy (VRE) in an electricity network can pose challenges to system reliability. Additional fast response dispatchable capacity must be introduced to the system to complement an increasing proportion of VRE generators such as wind and solar photovoltaic [4]. This may lead to new obligations in the network to ensure that the system reliability is maintained. For example, support payments are given in Germany to flexible plants to back up wind and solar, the cost of which is passed on to the final consumers via their electricity bills [5].

This paper studies a game-theoretical Cournot-based electricity market evolution model with emission and fast response dispatchable capacity constraints. The dual variable of the emission constraint at the Nash Equilibrium solution of the game is used to design the emission incentive policies and the dual variable of the fast response dispatchable capacity constraint at the NE point is used to design the fast response capacity incentive policies. We implement our developed model to Australia's five-node NEM market as the case study.

### B. Related Works

The problem of electricity market expansion for studying the future generation mix or the $CO_2$ emission abatement has been studied in [6]–[13], with least cost generation expansion planning models, and in [14]–[21], with imperfectly competitive market evolution models. However, the electricity market expansion problem with emission and fast response dispatchable capacity incentive policies has not been investigated in the literature.

A least cost electricity generation expansion planning model, in which the total technology and operation costs to meet a specified demand are minimized, is studied in [6] considering the demand side management, and in [7] considering the simultaneous expansion of the electricity and gas networks. A multi-period power generation expansion model considering the $CO_2$ emission target constraint is developed in [8], [9], which calculates the additional costs of achieving a $CO_2$ abatement target as the absolute and marginal costs of abatement. Instead of embedding an emission target constraint, the cost of $CO_2$ emission is added to the fuel cost as carbon tax to support more renewable power installation in [10].

Considering a target penetration level for renewables and an ensured payback period constraints, the incentive rate (subsidy) on new renewable technologies are calculated in

[11]. Incentive policies for renewable energies and emission reduction are also calculated using bilevel optimization models. Minimizing the total technology installation and operation costs in the lower level problem in [12] (or maximizing the social welfare in the lower level problem in [13]), the total policy intervention is minimized in the upper level problem to calculate the incentive policies of renewable subsidization or carbon taxation.

In order to investigate the strategic (price making) behavior of market participants, game-theoretical Cournot-based (oligopolistic) generation expansion models, i.e., market evolution models, are developed, for instance in [14], and are compared with least cost generation expansion models in [15]. Stochastic strategic generation expansion models are developed to include the uncertainty in conjectured-price response in [16] and the uncertainty in renewable power availability in [17]. Moreover, strategic generation expansion models have been utilized to manage the $CO_2$ emission level in the market, with an exogenous emission permit price in [18], and with a target emission constraint in [19], [20]. It is discussed in [20] that the dual variable of the emission target constraint can be interpreted as the carbon price in the market.

The electricity market expansion models are also required to ensure that there is enough dispatchable capacity connected to the network. In order to support more investment on dispatchable capacity, the total generation from wind and solar is limited to 30% of aggregated annual generation in each region in [9], and to incentivize the right level of dispatchable capacity investment, capacity market is designed beside the energy market in [21]. The *Blueprint for the Future* report [22] suggests to limit the total VRE generation to a proportion of dispatchable generation in Australia in order to ensure the system reliability and the minimum required dispatchable capacity in the network.

### C. Contributions

This paper proposes a strategically competitive electricity market expansion model, which includes the emission intensity reduction and fast response dispatchable capacity constraints. The Nash Equilibrium (NE) solution of our model is used to design the incentive policies on emission reduction and fast response dispatchable capacity support. In other words, the model is developed to illustrate the pathway towards a reliable and low emission future. The contributions of this paper are summarized as follows:

1) A game-theoretical Cournot-based electricity market expansion model is proposed, which solves a unified operation and installation problem, to find the future capacity mix of generation, storage and transmission players in the market. The problem formulation of our multi-region, multi-period electricity market expansion model is generalized to consider both strategic and regulated generation, storage, and transmission players in the market.
2) Capacity investment and retirement is calculated for all generation, storage and transmission players at different periods in our model, given the plant life of all technologies and the end of period remaining value of new invested technologies. The remaining value term is explained for generation players in our previous work [20].
3) Using the dual variable of the emission intensity reduction constraint at the NE point of our model, we calculate the emission tax and subsidy that generators are required to pay and receive for a targeted low emission market. We explicitly calculate which players must pay the emission tax and which players receive it as subsidy. Our problem formulation with the emission intensity constraint can be used to reach the emission control mechanism "Clean Energy Target" discussed in [22].
4) Using the dual variable of the fast response generation constraint at the NE point of our model, we calculate the capacity tax and subsidy that generators and storage firms are required to pay and receive in order to maintain the system reliable. We explicitly calculate which players must pay tax because their intermittent electricity generation and which players receive it as subsidy because of their fast response dispatchable electricity generation.

Under the proposed framework, an electricity generation mix for Australia's NEM is designed such that the emission intensity target is achieved and the reliability is maintained. The incentive policies on emission and fast response capacity are also calculated using the NE solution of the game.

The rest of the paper is organized as follows. The strategically competitive electricity market expansion model is formulated in Section II. The equilibrium analysis of the problem and the solution method are presented in Section III. The simulation results are presented in Section IV. The conclusion remarks are discussed in Section V.

## II. Strategically Competitive Electricity Market Expansion Model

In this section, we develop an electricity market expansion model which consists of generation, storage and transmission firms trading electricity in a multi-node energy-only wholesale electricity market. Let $\mathcal{N}_i^{\mathrm{ig}}$ be the set of intermittent generators, such as wind/PV farms and roof-top PVs, located in node $i$, $\mathcal{N}_i^{\mathrm{sg}}$ be the set of synchronous generators, such as coal, gas, hydro and solar thermal power plants, located in node $i$, $\mathcal{N}_i^{\mathrm{st}}$ be the set of storage firms, such as pump-hydros and batteries (cooperatively controlled or non-cooperative), located in node $i$, and $\mathcal{N}_i^{\mathrm{tr}}$ be the set of transmission lines connected to node $i$.

The market expansion problem is formulated as a Cournot-based game among the generation, storage and transmission players, which are introduced in detail in Section II-D. At the NE solution of the game, the capacity investment strategies of the firms, their bidding strategies as well as the equilibrium nodal prices are calculated. The market expansion game is solved under the emission intensity and fast response generation constraints, which their dual variables are used to calculate the tax and subsidy incentives.

### A. Inverse Demand Functions

In our model, the electricity price in node $i$ at investment period $y$, with duration of five years, and load time $t$, with

duration of one hour, is given by the following, commonly-used linear inverse demand function:

$$P_{iyt}\left(D_{iyt}\right) = \alpha_{iyt} - \beta_{iyt} D_{iyt}, \tag{1}$$

$$D_{iyt} = \sum_{m \in \mathcal{N}_i^{\mathrm{ig}}} q^{\mathrm{ig}}_{miyt} + \sum_{n \in \mathcal{N}_i^{\mathrm{sg}}} q^{\mathrm{sg}}_{niyt} + \sum_{b \in \mathcal{N}_i^{\mathrm{st}}} q^{\mathrm{st}}_{biyt} + \sum_{j \in \mathcal{N}_i^{\mathrm{tr}}} \left(\eta^{\mathrm{tr}}_{ij} q^{\mathrm{tr}}_{ijyt} - q^{\mathrm{tr}}_{jiyt}\right) \ \forall i, y, t \tag{2}$$

where $\alpha_{iyt}$ and $\beta_{iyt}$ are positive real values for the inverse demand function in node $i$ at period $y$, and load time $t$. Besides, $q^{\mathrm{ig}}_{miyt}$ is the electricity generation of intermittent generator $m$ in region $i$ , $q^{\mathrm{sg}}_{niyt}$ is the electricity generation of synchronous generator $n$ in region $i$, $q^{\mathrm{st}}_{biyt}$ is the electricity flow from storage firm $b$ in node $i$, and $q^{\mathrm{tr}}_{ijyt}$ is the electricity flow from node $j$ to node $i$ at period $y$, and load time $t$. Note that the total amount of power supply from the generation, storage and transmission firms in node $i$ is equal to the nodal net electricity demand, which represents the nodal electricity balance in our work.

Although roof-top PVs and residential batteries do not participate in the wholesale market, their operation affects the market price, i.e., shifts the inverse demand function up or down. For example, when new roof-top PVs with the generation amount of $\Delta D_{iyt}$ is installed, it shifts the inverse demand function in the wholesale market down, i.e., the equation (1) changes to $P_{iyt} = \alpha^{'}_{iyt} - \beta_{iyt} D_{iyt}$, where $\alpha^{'}_{iyt} = (\alpha_{iyt} - \beta_{iyt} \Delta D_{iyt})$. Equivalently, we can consider the generation of $\Delta D_{iyt}$ in the wholesale market and write the equation (1) as $P_{iyt} = \alpha_{iyt} - \beta_{iyt}\left(\Delta D_{iyt} + D_{iyt}\right)$.

Thus, instead of considering predetermined capacities of roof-top PVs and residential batteries on the demand side, we equivalently model them on the supply side as perfectly competitive players, and decide on their capacities in our model.

### B. Total Capacity and Investment Functions

In our model, any player can retrofit its capacity at any investment period $y$. The total capacity of each firm at period $y$, $Q_y$, is the sum of incumbent (old) capacities, $Q^{\mathrm{old}}_y$, which are given as exogenous input to the model, and new capacities, $Q^{\mathrm{new}}_y$, which are decision variables of players, as:

$$Q_y(Q^{\mathrm{new}}_{y' \le y}) = \sum_{y'=\max(1, y-PL+1)}^{y} Q^{\mathrm{new}}_{y'} + \sum_{y''=\mathrm{Y}_0-PL+y+1}^{\mathrm{Y}_0} Q^{\mathrm{old}}_{y''} \tag{3}$$

where $PL$ denotes the plant life of the corresponding technology of the firm, and $Y_0$ is the base year in our study. Note that firms in our model are able to decommission their capacities at any period before they reach their plant life and each technology must become retired in our model when it reaches its plant life.

Market expansion models which assume annualized investment cost for technologies do not take capacity retirement into account [16]. Instead of using the annualized investment cost, we consider the whole technology costs and deduct the end of period remaining value of new capacities [20] from their investment costs in our model as:

$$Inv_y = \left(1 - \frac{\max(0, PL + y - N_Y - 1)}{PL}\right) \tilde{Inv} \tag{4}$$

where $\tilde{Inv}$ is the actual investment cost of a unit and $Inv_y$ is the modified value of investment cost at period $y$ in our model. For instance, in a 25-year period simulation study, $N_Y = 25$, if a firm with the technology plant life of 20 years decides to install a new unit at year 21, it just pays $\frac{1}{4}$ of the actual investment cost in our model. Note that we include the yearly maintenance costs of technologies as part of their investment costs and do not consider them separately.

### C. The Emission and Capacity Incentive Policies

An upper bound on the emission intensity is considered in our model to ensure the emission intensity reduction in the market as:

$$\frac{\sum_{i,t} \sum_{n \in \mathcal{N}_i^{\mathrm{sg}}} q^{\mathrm{sg}}_{niyt} EF_{ni}}{\sum_{i,t} \sum_{n \in \mathcal{N}_i^{\mathrm{sg}}} q^{\mathrm{sg}}_{niyt} + \sum_{m \in \mathcal{N}_i^{\mathrm{ig}}} q^{\mathrm{ig}}_{miyt}} \le \left(1 - \alpha^{\mathrm{ER}}_y\right) EI^{\mathrm{CO_2}}_{Y_0} : \mu^{\mathrm{ER}}_y \ \forall y \tag{5}$$

where $EI^{\mathrm{CO_2}}_{Y_0}$ is the $CO_2$ emission intensity of the whole electricity sector at base (reference) year $Y_0$, $\alpha^{\mathrm{ER}}_y$ is the desired percentage of emission intensity reduction at period $y$ relative to the base period $Y_0$, $EF_{ni}$ is the emission factor of fossil-fueled synchronous generator $n$ in node $i$. The dual variable associated with this constraint, i.e., $\mu^{\mathrm{ER}}_y$, corresponds to the required emission tax/subsidy (first incentive policy) to achieve a level of emission intensity, as shown in Section III-C.

The second incentive policy is calculated based on the fast response dispatchable capacity constraint. The constraint limits the total VRE generation to a proportion of fast response generation during each investment period to ensure adequacy of fast response capacity in the network as:

$$\sum_{t} \left( \sum_{n \in \mathcal{N}_i^{\mathrm{sg}}} \alpha^{\mathrm{sg,FR}}_{ni} q^{\mathrm{sg}}_{niyt} + \sum_{b \in \mathcal{N}_i^{\mathrm{st}}} \alpha^{\mathrm{st,FR}}_{bi} q^{\mathrm{dis}}_{biyt} \right) \ge \alpha^{\mathrm{FR}} \sum_{t} \sum_{m \in \mathcal{N}_i^{\mathrm{ig}}} q^{\mathrm{ig}}_{miyt} \ : \ \mu^{\mathrm{FR}}_{iy} \ \ \forall i, y \tag{6}$$

where $\alpha^{\mathrm{FR}}$ is the fast response proportion coefficient, $\alpha^{\mathrm{sg,FR}}_{ni}$ is a binary coefficient which is one if firm $n$ in region $i$ is a fast response synchronous generator, such as gas-fired or hydro, $\alpha^{\mathrm{st,FR}}_{bi}$ is a binary coefficient which is one if firm $b$ in region $i$ is a pump-hydro or a cooperatively controlled battery, and $q^{\mathrm{dis}}_{biyt}$ is the electricity discharge level of the storage firm $b$ in node $i$. It is also shown in Section III-C that the required annual capacity subsidy/tax to ensure that there is enough fast

response capacity in the network is calculated based on the dual variable of the fast response constraint, $\mu^{\mathrm{FR}}_{iy}$:

Note that we can reduce the coefficient $\alpha^{\mathrm{FR}}$, i.e., the need for fast response capacity to achieve diversity dividends, by spreading the wind and solar generation across the network, which smooths the generation and ramping up and down of the total regional intermittent electricity generation [23].

### *D. The Market Expansion Game*

In this subsection, we introduce the market expansion game, the utility function of players and their decision variables. In our model, each firm decides on its expansion capacity and bidding strategies over the planning horizon, being either strategic or regulated. Strategic firms are called price maker players in the market and can potentially exercise market power to increase the price above the perfect competition level, but regulated firms are subject to regulations which impede them from exercising market power, i.e., have to act as price taker firms.

*Definition 1:* A strategic firm sets its strategies over the time horizon maximizing its aggregate expected profit, i.e., is a price maker player, but a regulated firm aims to maximize the social welfare, i.e., is subject to regulation and has to act as a price taker player [24].

In what follows, the variable $\mu$ indicates the associated Lagrange multiplier or dual variable of its corresponding constraint, the price function $P_{iyt}(.)$ refers to (1) and the total capacity function $Q(.)$ refers to (3).

*1) Intermittent Generation Firms:* The $m$th intermittent generator, i.e., wind or solar farm or roof-top PVs, in node $i$ maximizes its profit by solving the following optimization problem:

$$\max_{\substack{\{q^{\mathrm{ig}}_{miyt}\}_{yt} \\ \{Q^{\mathrm{ig,new}}_{miy}\}_{y}} \succeq 0} \sum_{y,t} \Delta\ell \frac{P_{iyt}(.)\, q^{\mathrm{ig}}_{miyt} - \left(c^{\mathrm{ig}}_{mi} q^{\mathrm{ig}}_{miyt} + \frac{d^{\mathrm{ig}}_{mi}}{2} {q^{\mathrm{ig}}_{miyt}}^2\right)}{(1+r)^y} + \gamma^{\mathrm{ig}}_{mi} \frac{\beta_{iyt} {q^{\mathrm{ig}}_{miyt}}^2}{2} - \sum_{y} \frac{Inv^{\mathrm{ig}}_{miy} Q^{\mathrm{ig,new}}_{miy}}{(1+r)^y} \quad (7a)$$

s.t.

$$q^{\mathrm{ig}}_{miyt} \le A^{ig}_{mit} Q^{\mathrm{ig}}_{miy}(.) \;:\; \mu^{\mathrm{ig}}_{miyt} \quad \forall y,t \quad (7b)$$

$$Q^{\mathrm{ig}}_{miy}(.) \le \bar{C}^{\mathrm{ig}}_{mi} \;:\; \mu^{\mathrm{ig,\bar{C}}}_{miy} \quad \forall y,t \quad (7c)$$

$$(5),(6) \quad (7d)$$

where $\Delta\ell$ is the length of each time load during each investment period, $Q^{\mathrm{ig,new}}_{miy}$ and $Q^{\mathrm{ig}}_{miy}(.)$ are the new capacity (variable) and the total generation capacity (function) of the intermittent (VRE) firm $m$ in node $i$ at period $y$, respectively. The first term in the summation in (7a) is the net present value of electricity generation revenue, the second term represents the generation cost, which is quadratic with coefficients $c^{\mathrm{ig}}_{mi}$ and $d^{\mathrm{ig}}_{mi}$, the third term denotes the regulation surplus when $\gamma^{\mathrm{ig}}_{mi}$ is one, given the discount rate $r$ over the periods $y \in \{1,...,N_Y\}$. The last term in (7a) is the total investment cost of new capacities, with unitary investment cost of $Inv^{\mathrm{ig}}_{miy}$, over the periods. Depending on the binary parameter $\gamma^{\mathrm{ig}}_{mi}$, the $m$th intermittent generation firm in node $i$ behaves strategically or in a regulated manner. The firm acts strategically when $\gamma^{\mathrm{ig}}_{mi}$ is zero or acts as a regulated firm when $\gamma^{\mathrm{ig}}_{mi}$ is one. Considering the $\frac{\beta_{iyt} {q^{\mathrm{ig}}_{miyt}}^2}{2}$ in the objective function, the firm becomes regulated (to behave like a price taker firm), which helps to increase the competition and consequently the social welfare in the market. The constraint (7b) considers the regional intermittent energy availability coefficient in load time $t$, $A^{ig}_{mit}$, and the constraint (7c) limits the electricity generation to the maximum potential capacity, $\bar{C}^{\mathrm{ig}}_{mi}$, e.g., the roof-top PV installation area limit.

*2) Synchronous Generation Firms:* The strategy of the $n$th synchronous generator, i.e., coal, gas, biomass, hydro or solar thermal firms, in node $i$ is obtained by solving the following optimization problem:

$$\max_{\substack{\{q^{\mathrm{sg}}_{niyt}\}_{yt} \\ \{Q^{\mathrm{sg,new}}_{niy}\}_{y}} \succeq 0} \sum_{y,t} \Delta\ell \frac{P_{iyt}(.)\, q^{\mathrm{sg}}_{niyt} - c^{\mathrm{sg}}_{ni} q^{\mathrm{sg}}_{niyt} + \gamma^{\mathrm{sg}}_{ni} \frac{\beta_{iyt} {q^{\mathrm{sg}}_{niyt}}^2}{2}}{(1+r)^y} - \sum_{y} \frac{Inv^{\mathrm{sg}}_{niy} Q^{\mathrm{sg,new}}_{niy}}{(1+r)^y} \quad (8a)$$

s.t.

$$q^{\mathrm{sg}}_{niyt} \le A^{\mathrm{sg}}_{ni} Q^{\mathrm{sg}}_{niy}(.) \;:\; \mu^{\mathrm{sg}}_{niyt} \quad \forall y,t \quad (8b)$$

$$q^{\mathrm{sg}}_{niyt} - q^{\mathrm{sg}}_{niy(t-1)} \le R^{\mathrm{up}}_{ni} A^{\mathrm{sg}}_{ni} Q^{\mathrm{sg}}_{niy}(.) : \mu^{\mathrm{sg,up}}_{niyt} \;\forall y,t \quad (8c)$$

$$q^{\mathrm{sg}}_{niy(t-1)} - q^{\mathrm{sg}}_{niyt} \le R^{\mathrm{dn}}_{ni} A^{\mathrm{sg}}_{ni} Q^{\mathrm{sg}}_{niy}(.) : \mu^{\mathrm{sg,dn}}_{niyt} \;\forall y,t \quad (8d)$$

$$\sum_{t} q^{\mathrm{sg}}_{niyt} \le RA^{\mathrm{sg}}_{niy} : \mu^{\mathrm{sg,RA}}_{niy} \;\forall n,i,y \quad (8e)$$

$$(5),(6) \quad (8f)$$

where $Q^{\mathrm{sg,new}}_{niy}$ and $Q^{\mathrm{sg}}_{niy}(.)$ are the new capacity (variable) and total generation capacity (function) of the synchronous firm $n$ in node $i$ at period $y$. The parameter $c^{\mathrm{sg}}_{ni}$ represents the firm's marginal operation and fuel cost of electricity generation and the parameter $Inv^{\mathrm{sg}}_{niy}$ is its unitary investment cost. Depending on the binary parameter $\gamma^{\mathrm{sg}}_{ni}$, the $n$th synchronous generator in node $i$ acts strategically when $\gamma^{\mathrm{sg}}_{ni}$ is zero or acts as a regulated firm when $\gamma^{\mathrm{sg}}_{ni}$ is one. The constraint (8b) limits the electricity generation to its energy flow capacity with availability coefficient $A^{\mathrm{sg}}_{ni}$. Constraints (8c) and (8d) ensure that the $n$th synchronous generator meets its ramping limits, with ramping up and down coefficients $R^{\mathrm{up}}_{ni}$ and $R^{\mathrm{dn}}_{ni}$, and constraint (8e) limits the electricity generation during period $y$ to energy availability limit $RA^{\mathrm{sg}}_{niy}$, e.g. the dam water availability limit for hydros.

*3) Storage Firms:* The strategy of the $b$th storage firm, i.e., pump-hydro, or cooperatively controlled or non-cooperative batteries (cooperative batteries is able to provide fast response generation in the network), in node $i$ is obtained by solving the following optimization problem:

$$\max_{\substack{\left\{q^{\text{dis}}_{biyt},q^{\text{ch}}_{biyt}\right\}_{yt}\succeq 0\\ \left\{Q^{\text{st}^{\text{f}},\text{new}}_{biy},Q^{\text{st}^{\text{v}},\text{new}}_{biy}\right\}_{y}\succeq 0\\ \left\{q^{\text{st}}_{biyt}\right\}_{yt}}} \sum_{y,t}\Delta\ell\frac{P_{iyt}\left(.\right)q^{\text{st}}_{biyt}+\gamma^{\text{st}}_{bi}\frac{\beta_{iyt}{q^{\text{st}}_{biyt}}^{2}}{2}}{(1+r)^{y}} - \sum_{y}\frac{Inv^{\text{st}^{\text{v}}}_{biy}Q^{\text{st}^{\text{v}},\text{new}}_{biy}+Inv^{\text{st}^{\text{f}}}_{biy}Q^{\text{st}^{\text{f}},\text{new}}_{biy}}{(1+r)^{y}} \tag{9a}$$

s.t.

$$q^{\text{st}}_{biyt}=\eta^{\text{dis}}_{bi}q^{\text{dis}}_{biyt}-\frac{q^{\text{ch}}_{biyt}}{\eta^{\text{ch}}_{bi}} \;:\; \mu^{\text{st}}_{biyt} \quad \forall y,t \tag{9b}$$

$$q^{\text{dis}}_{biyt}\le A^{\text{st}}_{bi}Q^{\text{st}^{\text{f}}}_{biy}(.) \;:\; \mu^{\text{dis}}_{biyt} \quad \forall y,t \tag{9c}$$

$$q^{\text{ch}}_{biyt}\le A^{\text{st}}_{bi}Q^{\text{st}^{\text{f}}}_{biy}(.) \;:\; \mu^{\text{ch}}_{biyt} \quad \forall y,t \tag{9d}$$

$$0\le\sum_{t'=1}^{t}\left(q^{\text{ch}}_{biyt'}-q^{\text{dis}}_{biyt'}\right)\Delta\le A^{\text{st}}_{bi}Q^{\text{st}^{\text{v}}}_{biy}(.):\mu^{\text{st,min}}_{biyt},\mu^{\text{st,max}}_{biyt} \quad \forall y,t \tag{9e}$$

$$q^{\text{dis}}_{biyt}q^{\text{ch}}_{biyt}=0 \;:\; \mu^{\text{dis/ch}}_{biyt} \quad \forall y,t \tag{9f}$$

$$(6) \tag{9g}$$

where $Q^{\text{st}^{\text{v}},\text{new}}_{biy}$ and $Q^{\text{st}^{\text{f}},\text{new}}_{biy}$ are the new volume and flow capacity (variable), and $Q^{\text{st}^{\text{v}}}_{biy}(.)$ and $Q^{\text{st}^{\text{f}}}_{biy}(.)$ are the total volume and flow capacity (function) of the storage firm $b$ in node $i$ at period $y$, respectively. Note that the unit for volume capacity is MWh (energy) and for flow capacity is MW (power). The parameters $Inv^{\text{st}^{\text{v}}}_{biy}$ and $Inv^{\text{st}^{\text{f}}}_{biy}$ are the firm's unitary volume and flow investment costs, respectively. Depending on the binary parameter $\gamma^{\text{st}}_{bi}$, the $b$th storage firm in node $i$ acts strategically when $\gamma^{\text{st}}_{bi}$ is zero and acts as a regulated firm when $\gamma^{\text{st}}_{bi}$ is one. The equality (9b) defines the net output/input flow of electricity, $q^{\text{st}}_{biyt}$, from/to storage firm $b$ in node $i$. The constraints (9c) and (9d) limit the energy flow (discharge $q^{\text{dis}}_{biyt}$ and charge $q^{\text{ch}}_{biyt}$) of the firm to its flow (discharge/charge) capacity with availability factor $A^{\text{st}}_{bi}$. Constraint (9e) ensures the volume capacity limit of the storage firm is always met. Finally, constraint (9f) prevents the storage firm charge and discharge simultaneously, which is the only non-linear constraint in our model. Note that because of the fast response constraint (6) in our model, we need the constraint (9f) to prevent simultaneous charge and discharge of the storage firm. This is essentially because the situation which prevents concurrent charge and discharge of a storage firm at the NE point of the game is violated, see [25] for more details.

*4) Transmission Firms:* The strategy of the transmission line between nodes $i$ and $j$, which buys and sells electricity in regions it connects, is obtained by solving the following optimization problem:

$$\max_{\substack{\left\{q^{\text{tr}}_{ijyt},q^{\text{tr}}_{ijyt}\right\}_{yt}\\ \left\{Q^{\text{tr,new}}_{ijy},Q^{\text{tr,new}}_{jiy}\right\}_{y}\succeq 0}} \sum_{y,t}\Delta\ell\Bigg(\frac{\left(\eta^{\text{tr}}_{ij}P_{jyt}\left(.\right)-P_{iyt}\left(.\right)\right)q^{\text{tr}}_{jiyt}}{(1+r)^{y}}+\frac{\left(\eta^{\text{tr}}_{ij}P_{iyt}\left(.\right)-P_{jyt}\left(.\right)\right)q^{\text{tr}}_{ijyt}}{(1+r)^{y}}+\gamma^{\text{tr}}_{ij}\frac{\left(\eta^{\text{tr}}_{ij}{}^{2}\beta_{iyt}+\beta_{jyt}\right)\frac{{q^{\text{tr}}_{ijyt}}^{2}}{2}+\left(\eta^{\text{tr}}_{ij}{}^{2}\beta_{jyt}+\beta_{iyt}\right)\frac{{q^{\text{tr}}_{jiyt}}^{2}}{2}-\eta^{\text{tr}}_{ij}\left(\beta_{jyt}+\beta_{iyt}\right)q^{\text{tr}}_{ijyt}q^{\text{tr}}_{jiyt}}{(1+r)^{y}}\Bigg) - \sum_{y}\frac{\frac{Inv^{\text{tr}}_{ijy}}{2}\left(Q^{\text{tr,new}}_{ijy}+Q^{\text{tr,new}}_{jiy}\right)}{(1+r)^{y}} \tag{10a}$$

s.t.

$$q^{\text{tr}}_{ijyt}\le A^{\text{tr}}_{ij}Q^{\text{tr}}_{ijy}(.) \;:\; \mu^{\text{tr}}_{ijyt} \quad \forall y,t \tag{10b}$$

$$Q^{\text{tr,new}}_{ijy}=Q^{\text{tr,new}}_{jiy} \;:\; \mu^{\text{tr,Q}}_{ijy} \quad \forall y \tag{10c}$$

where $Q^{\text{tr,new}}_{ijy}$ and $Q^{\text{tr}}_{ijy}(.)$ are the new capacity (variable) and the total transmission capacity (function) of the transmission firm between nodes $i$ and $j$ at period $y$. The first term in summation in (10a) is the electricity profit of transmitting electricity from node $i$ to node $j$, the second term is the backward profit, the third term denotes the regulation surplus and the last term is the total investment cost of new capacities, with unitary investment cost of $Inv^{\text{tr}}_{ijy}$. Depending on the binary parameter $\gamma^{\text{tr}}_{ij}$, the transmission line between nodes $i$ and $j$ acts strategically when $\gamma^{\text{tr}}_{ij}$ is zero or acts as a regulated firm when $\gamma^{\text{tr}}_{ij}$ is one. Note that the electricity markets with regulated transmission lines are discussed as *electricity markets with transmission constraints* in the literature, e.g., [24], [26], [27]. The constraint (10b), in order to consider the congestion in the transmission network, limits the electricity flow to the capacity of transmission lines with availability coefficient $A^{\text{tr}}_{ij}$, and the constraint (10c) ensures that transmission capacity on both directions of the line is equal in our model.

Note that the profit maximization problem (10a) looks more complex than our previous formulation in [25] because of considering the transmission efficiency, $\eta^{\text{tr}}_{ij}$, which was missing before.

## III. Solution Methodology

In this section, we first provide a game-theoretic analysis of the market expansion game between generation, storage and transmission players. Next, we explain a method for solving the game based on a Mixed Complementarity Problem (MCP).

### A. Game-theoretic Analysis of the Market Expansion Model

To solve the market expansion game, we need to study the best response functions of all firms participating in the market. The best response of any player satisfies the necessary and sufficient Karush-Kuhn-Tucker (KKT) conditions. The KKT conditions are the derivative of Lagrangian function of each player $L$ respect to all its decision variables, e.g. $q$, and the complementary (slackness) conditions:

$$\frac{\partial L}{\partial q}\le 0 \;\perp\; q\ge 0 \text{ if } q\ge 0 \tag{11a}$$

$$\frac{\partial L}{\partial q}=0 \text{ if } q \text{ is free} \tag{11b}$$

where the perpendicularity sign, $\perp$, indicates that one of the adjacent inequalities must at least be satisfied as an equality [28].

Then, any intersection of all firms' best response functions will be a NE. At the NE strategy of the game, no player has any incentive to unilaterally deviate its strategy from the NE point. Note that (9f), which is nonlinear, is the only constraint in our model that violates the sufficient conditions of Theorem 4.4 in [29] for existence of NE point. However, in our numerical results, we find the NE point of the game by varying the initial point of the optimization algorithm.

### B. The Mixed Complementarity Problem

The NE solution is by definition the intersection of best responses of all players. Therefore, it satisfies the KKT conditions of all market players, that is, (7a-7d), (8a-8f), (9a-9g), and (10a-10c). Consequently, the NE solution, if exists, is the result of the following Mixed Complementarity Problem (MCP):

$$\begin{aligned}&\mathrm{KKT}(7a\text{–}7d), \mathrm{KKT}(8a\text{–}8f), \mathrm{KKT}(9a\text{–}9g), \mathrm{KKT}(10a\text{–}10c)\\ &m \in \{1, ..., N_i^{\mathrm{ig}}\}, n \in \{1, ..., N_i^{\mathrm{sg}}\}, b \in \{1, ..., N_i^{\mathrm{st}}\},\\ &i, j \in \{1, ..., I\}, t \in \{1, ..., N_T\}, y \in \{1, ..., N_Y\}\end{aligned}$$

where the decision variables are the bidding strategies of all players, and set of Lagrange multipliers or dual variables in KKT conditions. We used the PATH solver in GAMS software to solve the MCP problem.

Because of the specific structure of the electricity market expansion model developed in this paper, we can also find the NE point in the game by solving a centralized optimization problem, based on the methodology explained in [20], [30]. However, we write the KKT equations and solve the MCP problem to elaborately illustrate how the dual variables of the emission and fast response constraints at the NE point of the game can be interpreted as tax/subsidy in our model. Note that, our numerical results show that both solution methods yield a unique NE point in the game. However, due to the non-convex constraint (9f), we cannot provide a theoretical statement on existence or uniqueness of the NE solution.

### C. Interpreting the Dual Variables as Tax and Subsidy

In this subsection, based on dual variable of the emission constraint (5), $\mu_y^{\mathrm{ER}}$, and dual variable of the fast response constraint (6), $\mu_{iy}^{\mathrm{FR}}$, at the NE point of the game, we calculate the $CO_2$ emission tax/subsidy and the economic value of fast response capacity, respectively, in our model.

Firstly, we explain the carbon taxing/subsidizing mechanism in our model. Base on the KKT equations of the problem, the term $\frac{(1+r)^y}{\Delta\ell}\left(EF_{ni} - \left(1-\alpha_y^{\mathrm{ER}}\right) EI_{Y_0}^{\mathrm{CO_2}}\right)\mu_y^{\mathrm{ER}}$ constitutes a portion of the price function, $P_{iyt}(.)$, when $q_{niyt}^{\mathrm{sg}}$ is positive, which can be interpreted as the tax/subsidy the synchronous generator $n$ in node $i$ must pay/receive per each MWh electricity generation at period $y$. Similarly, the term $\frac{(1+r)^y}{\Delta\ell}\left(1-\alpha_y^{\mathrm{ER}}\right) EI_{Y_0}^{\mathrm{CO_2}}\mu_y^{\mathrm{ER}}$ is equal to the subsidy the intermittent renewable generator $m$ in node $i$, which is wind or solar, receives per each MWh electricity generation at period $y$.

Secondly, we explain the fast response capacity mechanism in our mode. Base on the KKT equations of the problem, the terms $\alpha^{\mathrm{FR}}\mu_{iy}^{\mathrm{FR}}$, $\alpha_{ni}^{\mathrm{sg,FR}}\mu_{iy}^{\mathrm{FR}}$, and $\alpha_{bi}^{\mathrm{st,FR}}\mu_{iy}^{\mathrm{FR}}$ constitute a portion of the price function, $P_{iyt}(.)$, when $q_{miyt}^{\mathrm{ig}}$, $q_{niyt}^{\mathrm{sg}}$ and $q_{biyt}^{\mathrm{dis}}$ are positive, respectively. Therefore, at the NE solution the term $\frac{\Delta\ell\sum_t \alpha^{\mathrm{FR}}\mu_{iy}^{\mathrm{FR}} q_{miyt}^{\mathrm{ig}}}{Q_{miy}^{\mathrm{ig}}(.)}$ is equal to the fast response capacity tax that in average one MW intermittent generator pays per each period $y$, and the terms $\frac{\Delta\ell\sum_t \alpha_{ni}^{\mathrm{sg,FR}}\mu_{iy}^{\mathrm{FR}} q_{niyt}^{\mathrm{sg}}}{Q_{niy}^{\mathrm{sg}}(.)}$, and $\frac{\Delta\ell\sum_t \alpha_{bi}^{\mathrm{st,FR}}\mu_{iy}^{\mathrm{FR}} q_{biyt}^{\mathrm{dis}}}{Q_{biy}^{\mathrm{st,f}}(.)}$ are equal to the fast response capacity subsidy that in average one MW synchronous generator and one MW storage firm receives per each period $y$, respectively.

### D. The Market Expansion Model in Practice

Based on the dual variables of the emission constraint (5) and the fast response constraint (6) at the NE point of the game, i.e., $\mu_y^{\mathrm{ER}^*}$, and $\mu_{iy}^{\mathrm{FR}^*}$, the market players solve the corresponding optimization problems with their new objective functions, disregarding the emission and fast response constraints. Therefore, in practice, the intermittent generator $m$ in region $i$, disregarding the constraints (5), (6), equivalently solves its optimization problem (7) with the following additional term in its objective function:

$$+\sum_{y,t}\left(1-\alpha_y^{\mathrm{ER}}\right) EI_{Y_0}^{\mathrm{CO_2}}\mu_y^{\mathrm{ER}^*} q_{miyt}^{\mathrm{ig}} - \sum_{y,t}\alpha^{\mathrm{FR}}\mu_{iy}^{\mathrm{FR}^*} q_{miyt}^{\mathrm{ig}},$$

the synchronous generator $n$ in region $i$, disregarding the constraints (5), (6), equivalently solves its optimization problem (8) with the following additional term in its objective function:

$$-\sum_{y,t}\left(EF_{ni} - \left(1-\alpha_y^{\mathrm{ER}}\right) EI_{Y_0}^{\mathrm{CO_2}}\right)\mu_y^{\mathrm{ER}^*} q_{niyt}^{\mathrm{sg}} + \sum_{y,t}\alpha_{ni}^{\mathrm{sg,FR}}\mu_{iy}^{\mathrm{FR}^*} q_{niyt}^{\mathrm{sg}},$$

the storage firm $b$ in region $i$, disregarding the constraint (6), equivalently solves its optimization problem (9) with the following additional term in its objective function:

$$+\sum_{y,t}\alpha_{bi}^{\mathrm{st,FR}}\mu_{iy}^{\mathrm{FR}^*} q_{biyt}^{\mathrm{dis}},$$

and the transmission line between nodes $i$ and $j$ solves the same optimization problem (10). Note that the solution of the updated market expansion model with the tax and subsidy terms is exactly equal to the NE solution of the game.

Note that the market operator or a government entity solves our game model and calculates the equilibrium values of $\mu_y^{\mathrm{ER}^*}$, and $\mu_{iy}^{\mathrm{FR}^*}$. Any inaccurate information used in calculating the tax/subsidy amounts may lead to significant deviation from the desired emission and reliability levels in the market.

## IV. Case Study and Simulation Results

In this section, we apply our market expansion framework to the Australia's NEM. NEM consists of five loosely intercon-

nected states: South Australia (SA), Queensland (QLD), Tasmania (TAS), Victoria (VIC), and New South Wales (NSW). The investment is calculated every five years from 2017 to 2052 in our model, considering a representative (averaged) 24-hour operation time (load time) horizon. The coefficients $\alpha$ and $\beta$ in (1) are calibrated based on average levels of historical demand and price recorded in five states of NEM in 2016-2017, with the price and demand error terms of 6.4% and 4.7%, respectively. Synchronous generators include classical coal, gas, hydro, and biomass plants in addition to the new emerging technology of solar thermal, and the intermittent generators consist of wind farms, PV farms and roof-top PVs. Storage technologies include pump-hydros, cooperatively controlled and non-cooperative batteries. The technology characteristic data and the incumbent capacities of the synchronous and intermittent generators, storage technologies, and interconnectors existing in NEM are gathered from [9], [31], [32].

The investment cost of any technology reduces as time goes on with the given de-escalation rates [31], which are input to our model. Based on the de-escalation rates, the mature generation technologies like coal, gas, biomass and hydro do not show significant investment cost reduction, whereas wind, PV, and solar thermal are expected to have 30%, 42%, and 53% investment cost reduction by 2052, respectively. The largest investment cost reduction is forecast for battery storage technology, which is about 68% by 2052. Note that there is uncertainty about the evolution of technology costs [33], and different technology cost assumptions may lead to dissimilar results. However, we have used the best available estimates and widely accepted parameters in our simulations.

The parameter $\alpha^{\mathrm{FR}}$ used in fast response constraint (6) is equal to 0.8 in our simulations, which is the average of proportion coefficients between intermittent and dispatchable electricity in [9], [22]. Note that we can increase the system reliability by increasing the parameter $\alpha^{\mathrm{FR}}$.

### A. Impact of Emission Reduction Policy on Market Expansion

In our study, the coefficient $\alpha^{\mathrm{ER}}$, is set to force 0% up to 100% emission intensity reduction by 2052 compared to 2017. Fig. 1 compares the net increase or decrease of capacity for generation, Fig. 1(a), storage and transmission, Fig. 1(b), technologies by 2052 in NEM, given the emission intensity reduction target. Based on this figure, increasing the emission intensity target up to 45% will not affect the net generation capacity. This is because clean electricity technologies are competitive enough to penetrate and reduce the emission intensity at least by 45% by 2052. However, to achieve a higher level of emission reduction target, it is required to set emission tax/subsidy incentive policies. The emission tax/subsidy incentives lead to accelerate the closure of coal and gas plants, from -10.9 GW and -5.5 GW to -19.9 GW and -8.3 GW, respectively, and the addition of renewable generators, from 9.3 GW to 22.2 GW for synchronous renewables and from 26.8 GW to 40.8 GW for intermittent renewables, in the network by 2052.

The high penetration of intermittent generation technologies is accompanied by high levels of storage in both forms of pump-hydro and cooperatively controlled batteries, which increase at most by 9.5 GW and 12.1 GW until 2052, respectively, and also high levels of interconnector between states, which increases at most by 3.7 GW until 2052. The non-cooperative batteries, which just make profit from energy arbitrage, cannot compete with cooperatively controlled batteries which make profit from both energy arbitrage and fast response support. In high emission intensity reduction target cases, very low level of investment is made on batteries without fast response provision capability (non-cooperative batteries) in the network.

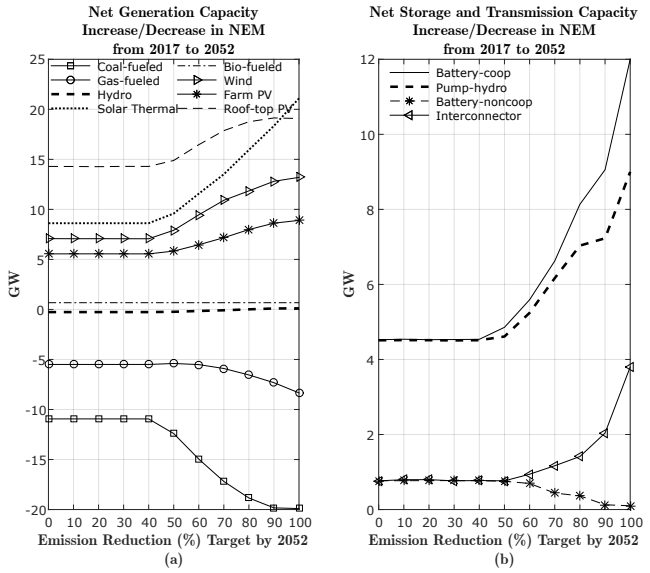



Fig. 1: Net increase/decrease of capacity for (a) generation and (b) storage and transmission technologies by 2052 in NEM for different target levels of emission intensity reduction.

In the following subsections, we compare our simulation results for just two cases of (i) No Emission Intensity Reduction policy (ii) 80% Emission Intensity Reduction policy in NEM by 2052 (zero emission scenarios in Australia until 2050 and 2070 are discussed in [31]). Note that even in the first case the emission intensity reduces almost by 45%, which means that emission intensity reduction will happen even without any emission policy.

### B. Impact of Emission Reduction Policy on Electricity Prices and Demands

The emission intensity reduction target affects the trajectory of electricity prices and demands in NEM during 2017-2052. Fig. 2(a) illustrates the average wholesale prices in NEM by 2052 with and without implementing the emission reduction policy. It can be seen that the market price is extremely high in 2017, which is the consequence of exercising market power by coal and gas generation firms. The price reduction trend continues for the next twenty years, i.e., until 2037. In fact, investment on renewable technologies increases the competition and reduces the prices for that period. Renewable generation firms, due to their sizes, benefit less from market power than conventional generators. By 2037, a large portion

of coal power plants are closed down in our model and the cost of installing new generation capacities raises the wholesale prices again during 2037-2052. Surprisingly, in the price declining period, i.e., 2017-2037, imposing the emission intensity reduction policies comparatively lowers the prices by 5%, which is related to the market power level. Penetration of renewables increases the competition (reduces the market power) and leads to lower prices.

Fig. 2(b) compares the average wholesale and net demand levels in NEM by 2052 with and without implementing the emission reduction policy. Note that the net demand includes the roof-top PV generation in addition to the wholesale demand. The divergence of the net and wholesale demand levels is caused by penetration of roof-top PVs in the network. Roof-top PV generation increases by 3.93 times in No Emission Reduction Policy case and by 4.84 times in 80% Emission Reduction Policy case until 2052, which shows that roof-top PV is competent enough to penetrate enormously by 2052 with or without emission incentive policy.

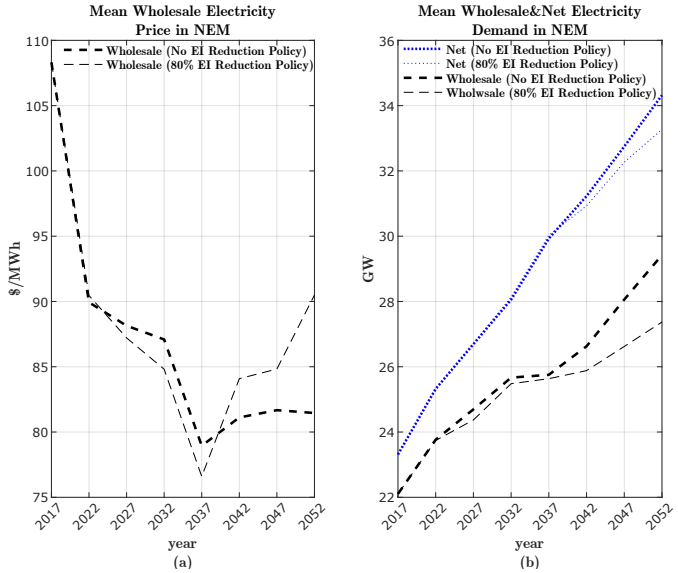



Fig. 2: The average yearly (a) wholesale prices and (b) net and wholesale demands in NEM, without or with emission reduction policy (net demand =wholesale demand + roof-top PV).

## C. Carbon Tax&Subsidy Design

We design the emission incentives based on the dual variable of the emission intensity constraint, which is called carbon price, at the NE point in our model. Implementing 80% Emission Intensity Reduction policy, the emission intensity must uniformly decrease from the base year level of 0.727 $\mathrm{tonne}_{\mathrm{CO_2}}/\mathrm{MWh_e}$ in 2017 to 0.145 $\mathrm{tonne}_{\mathrm{CO_2}}/\mathrm{MWh_e}$ in 2052. Fig. 3 (a) shows the calculated carbon price at different years to reach 80% emission intensity reduction by 2052. The carbon price moves upward in the beginning stage, up to year 2032, then decreases during 2032-2042, and goes up again at the final stage, 2042-2052. The closure of coal and gas power plants, which are at their end of life, mostly happens during 2032-2042, which reduces the emission intensity and carbon price level. However, higher levels of carbon price is calculated in our model to achieve higher levels of emission intensity reduction at the final stage, regarding the uniform reduction of emission intensity from 2017 to 2052.

Fig. 3 (b) indicates the average amounts of tax and subsidy that any type of generator pays or receives each year based on their electricity generation emission intensity and the calculated carbon price of that year. As coal-fueled generators have emission intensities much higher than the emission intensity target levels, they always pay carbon tax in the market. The gas-fueled generators have lower emission intensities and do not pay significant carbon penalty until 2042. The renewable generators, including wind, PV, solar thermal, bio-fueled, and hydro, receive the carbon subsidy in the market, as their generation emission intensity is zero. One kW capacity of solar thermal and bio-fueled generators are more efficient in reducing the emission intensity than one kW of wind, PV or even hydro, and thus receive higher emission subsidy in average.

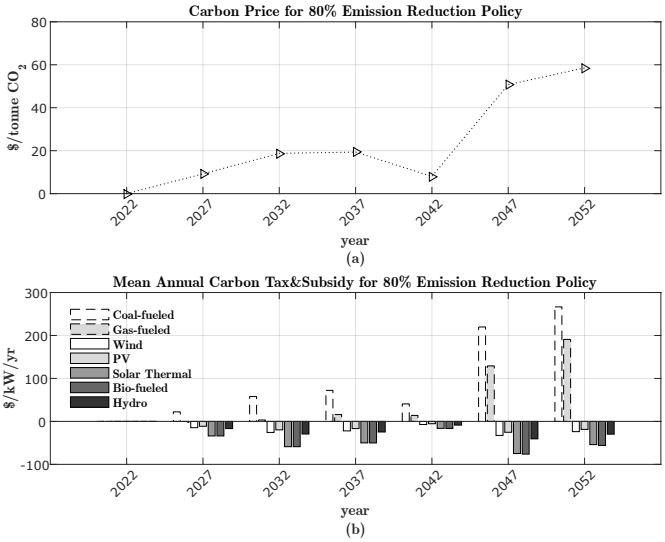



Fig. 3: The trajectory of (a) carbon price, (b) carbon tax (positive) and subsidy (negative) of different generation types during 2017-2052.

## D. Fast Response Capacity Tax&Subsidy Design

The other tax and subsidy incentive is calculated based on the dual variable of the fast response dispatchable generation constraint at the NE point in our model. Intermittent generators, i.e., wind and PV, are vulnerable to generation fluctuation due to wind and solar energy availability. Therefore, there must be adequate fast response generation capacity to dispatch even out of merit, i.e., even when their marginal cost of generation is above the market price, if wind or solar is lacking. As fast response generators may dispatch out of merit, they need to be subsidized. The subsidy is provided by taxing the intermittent generators. Fig. 4 indicates the level of fast response tax and subsidy for different generation types during 2017-2052, with and without emission intensity reduction policy. It can be seen

that implementing the emission reduction policy, which leads to higher levels of intermittent generation in the market, we calculate higher amounts of fast response tax and subsidy for all generators. Moreover, the subsidy level is not the same for different generation types. One kW pump-hydro receives higher subsidy for fast response provision than one kW battery as pump-hydros generally have larger energy storage tanks (kWh). However, the battery's fast response subsidy becomes more than the pump-hydro's in 2052 due to the decline in investment cost of the battery tanks. The subsidy on hydro plants uniformly increases by time, but the subsidy on gas-fueled plants increases significantly after 2042, as they have to pay considerable amounts of emission tax at those times.

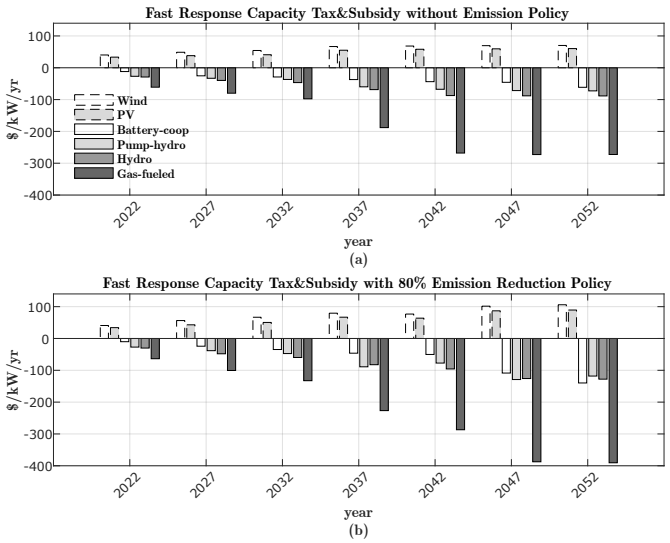



Fig. 4: The trajectory of fast response capacity tax (positive) and subsidy (negative) for (a) No Emission Reduction policy, (b) 80% Emission Intensity Reduction policy.

### *E. Impact of Emission Reduction Policy on Market Surpluses and Social Welfare*

The emission intensity reduction target affects the levels of supply/demand surpluses and social welfare in NEM. Social welfare is defined as the supply (generation+storage+transmission) surplus plus the consumer surplus [34]. Fig. 5 illustrates the normalized level of aggregated demand/supply surpluses and social welfare in NEM during 2017-2052 for different target levels of emission intensity reduction, $\alpha^{\mathrm{ER}}$. The demand/supply surpluses and social welfare are normalized with their base values, which are calculated when $\alpha^{\mathrm{ER}}$ is zero. It can be seen that the emission intensity reduction in NEM leads to at most 2% and 3% social welfare and consumer surplus reductions, respectively. Moreover, the supply surplus (profit) reaches its minimum level at 80% emission intensity reduction, but increases by 5% above its normalized level when emission intensity reduces by 100%. However, the emission intensity reduction above 90% leads to significant consumer surplus reduction and is not favorable for consumers.

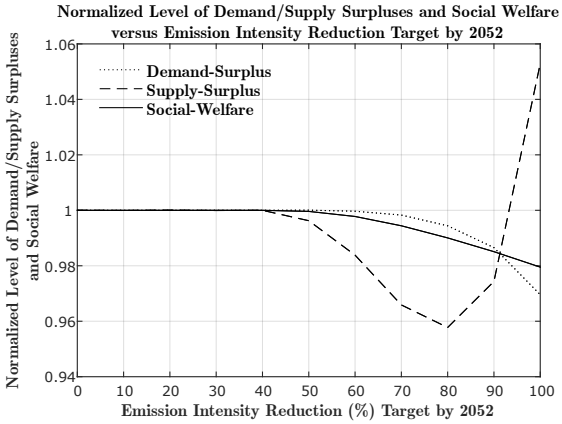



Fig. 5: Normalized levels of demand/supply surpluses and social welfare by 2052 in NEM for different target levels of emission intensity reduction.

### *F. Impact of Market Power on Market Expansion*

In this subsection, we compare our simulation results with the scenario when market power is disregarded in the game, i.e., a perfectly competitive market. Fig. 6 illustrates our simulation results for the generation, storage and transmission capacities in NEM at the end of 2052 with and without market power consideration when there isn't any emission policy, Fig. 6(a), and when 80% emission intensity reduction policy is implemented, Fig. 6(b). It can be seen that disregarding the market power, the investment on intermittent renewables, i.e., wind and solar PV, reduces almost by 60% in both emission policy cases due to lower market prices. Lower market prices decreases the investment attraction on intermittent renewables. Disregarding the market power results in more investment on synchronous generation, specifically coal and solar thermal in without and with emission reduction policy cases, respectively, in our model. When market power is disregarded, investment on gas generation is almost zero in our model due to its high operation and fuel cost. Investment on storage technologies also decreases without considering the market power.

## V. Discussion

- Numerous factors, such as technology investment cost, maintenance, operation and fuel costs, and different types of tax/subsidy incentive policies, affect the future generation technology mix in an electricity market. The future of market prices, generation and demand levels are very sensitive to those factors. For instance, the total capacity of non-cooperative batteries, which just make profit from energy arbitrage, is much less than that of the cooperatively controlled batteries, which make profit from both energy arbitrage and fast response service provision, despite having similar investment costs.
- Emission intensity reduction policies do not necessarily increase the average electricity prices all the times. Considering the Emission Intensity Reduction policy in our model, we calculated lower prices relative to No Emission Reduction policy scenario in the market until 2042. We also found that the price increase due to implementing the emission policies

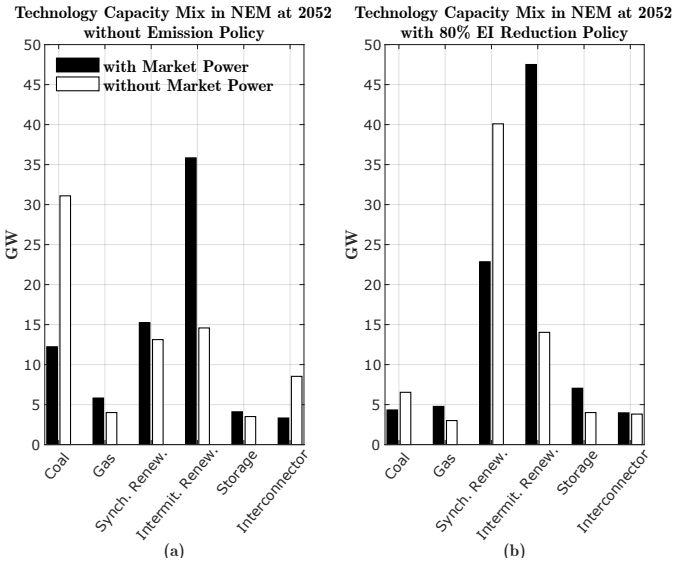



Fig. 6: Technology capacity mix in NEM with and without considering market power for (a) No Emission Reduction policy, (b) 80% Emission Intensity Reduction policy.

after 2042 happens at off peak times and even slightly reduces the peak time prices. This discussion is similar to the recent findings in [22].

- Emission incentive policies, which are calculated based on the dual variable of the emission constraint, can be used to penalize the pollutant generators and to reward the renewables and clean technologies. It is observed in our simulations that the retirement of the incumbent coal-fueled and gas-fueled generators reduces the carbon price level and subsequently the emission incentive policy levels in 2042. Thereafter, carbon price rises again to retain the emission intensity reduction trend in the market.
- The incentive policies of fast response capacity tax and support, which are calculated based on the dual variable of the fast response generation constraint, can be used to penalize the intermittent generators and subsidize the fast response capacities. Gradual retirement of the incumbent gas-fueled plants and penetration of intermittent generators lead to higher levels of subsidy to ensure existence of enough fast response capacity in the market.
- The high level of VREs integration in the market is mainly because of their cost declining trajectory and the exodus by the ageing coal power plants in the market, not because of their market power. In fact, the strategic intermittent generation firms limit their investment level in the market to increase the expected electricity prices in future (respect to their market power). Therefore, considering the VREs as regulated players (without market power), we can expect more investment on VRE in the market compared to the situation when VREs possess market power.
- Considering the market power in a market expansion model significantly affects the technology expansion decisions. Disregarding the market power, high electricity prices are not calculated in the model, which does not provide enough incentive for more recent technologies, like intermittent generators and batteries, to highly penetrate in the market.
- The high level of investment on synchronous renewable capacity, like solar thermal, which may have heat energy storage system or may be a hybrid system that use other fuels during periods of low solar radiation, and battery storage can also prevent the inertia and frequency response problems in electricity networks with high level of intermittent generation, as discussed in [4].
- Although the emission and fast response policies considered in our model are based on the policies suggested in [22] for Australia, we can design different types of emission reduction policies, such as C&T carbon policy or RPS, by updating the emission constraint (5), and design different reliability policies by updating the flexibility constraint (6).
- Daily reserve requirement in electricity networks considering the ramping capability of storage facilities or spinning reserve generators is studied in [35]–[37], which solve cost allocation problems to find the lowest cost solution in the market. However, these models do not consider the impact of market power on electricity prices. In the future, we aim to develop the stochastic version of our game-theoretic market expansion model with reserve margin and operating reserves constraints and calculate the tax/subsidy policies required to assure the satisfaction of those constraints in the market using their dual variables at the NE point.

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